PEYTO

Energy Trust

2004

Annual Report

Chairman's Message

A cornerstone of the Peyto style is that the unitholders are treated like fellow-owners. All of the members of the Board of Directors and senior management have substantial investments in Peyto. For most, Peyto is by far their largest investment. The objective of the Peyto team is obvious to everyone. The aim is to build value for the long-term benefit of all the unitholders. The interests of the Board and management are solidly aligned with those of the other unitholders.

The CEO has provided Peyto's industry-leading statistics elsewhere in this report. Clearly, the objective of value-creation is being met. What might not be so clear is that Peyto believes that what it is accomplishing today is highly repeatable. The part of the central Deep Basin of Alberta, which is Peyto's entire focus for exploration and development, is about one hundred miles in length, and is believed to hold many further opportunities. It is encouraging that management continues to invest substantially in Peyto trust units. This includes almost the entire after-tax proceeds of the 2004 bonuses.

One of the primary goals of Peyto's Board is to be an industry leader in "transparency", or what I prefer to call "clarity". We aim to provide the unitholders with clear information that answers all the questions an owner would want to ask. This should be evident in this Annual Report, Peyto's web site (at www.peyto.com), and all of our public documents. We regard our web site, incidentally, as a primary means of telling investors what Peyto is all about, and how we are doing. The site is constantly being improved and updated.

I would like to particularly thank two of Peyto's independent directors, Mick MacBean and Brian Craig, who chair the Audit and Reserves Committees, respectively. Their leadership on these committees assures the precision and clarity of Peyto's financial and reserves statements. I learn something from them every time we get together. It may be of interest that independent directors, who comprise the membership of all three Board committees, meet separately from management members of the Board several times a year, which we consider important in fulfilling our responsibilities.

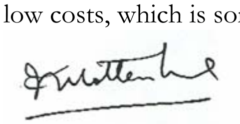
Over the last six years, Peyto's market capitalization has grown to $2.5 billion, an amazing accomplishment in such a short time. Notably, the growth of the enterprise has been entirely with the drill bit, and not by acquisition. This is a compliment to the technical skills of the Peyto team.

Growth such as Peyto is experiencing means, however, that we need more people. We shall also unavoidably lose a few fine people who will leave for any of a variety of personal reasons. Other people will be replaced, as new skill sets are required. This is an evolutionary and dynamic process, and one that the Board is confident Peyto can handle.

Our experience is that Peyto's culture and reward system is a magnet for able people in the industry. Don Gray's leadership style pushes most decisions down to the Peyto team. This empowerment of skilled individuals is an important part of the culture I referred to, and it is a great contributor to job satisfaction.

Peyto has completed another wonderful year, one of which the team can be very proud. The Board assesses results primarily via per unit progress and performance relative to our competitors. It is interesting to note, however, that in absolute terms, Peyto's 2004 return on equity (ROE) of 50% and return on capital employed (ROCE) of 22% were outstanding.

I should make a final comment on risk control. While Peyto management tends to be relatively optimistic about the outlook for natural gas and gas liquids prices over the next few years, we cannot be certain about future price trends. Peyto's hedge book is a kind of low cost (free in 2004) short-term insurance policy. More importantly, our best protection against adverse resource price movements is our low costs, which is something we can control.



C. Ian Mottershead
Chairman of the Board

Report from the President

Peyto Energy Trust ("Peyto") is a leader in the exploration and development of natural gas in western Canada. By design, our core areas are located in Alberta's premier gas exploration area, the Deep Basin. The combination of our solid foundation and our ability to profitably find and develop oil and natural gas reserves makes Peyto a unique energy trust. We are proud to present our operating and financial results for the fourth quarter and 2004 fiscal year.

As with previous years, Peyto continues to rank at the top of the Canadian energy sector. The following summarizes certain of the Trust's attributes at year end.

- Long reserve life - Proved 12.2 years, Proved Plus Probable 17.2 years
- Low operating costs - $1.05/boe
- Low base general and administrative costs - $0.12/boe
- High netback - $30.57/boe
- High operatorship - over 95% of production
- Low cash distribution ratio - 44% of fourth quarter 2004 funds from operations
- Low debt to funds from operations ratio - 0.9 (net debt, before provision for future compensation, divided by annualized fourth quarter 2004 funds from operations)
- Monthly cash distribution of $0.22 per unit - production and reserve growth on a per unit basis has allowed us to increase our distributions three times, or by 47% on aggregate, since the conversion to a trust
- Transparent capital structure - no convertible debentures, no exchangeable shares, no stock options, no warrants

We believe that our results for 2004 are consistent with our history of industry leading performance. The following summarizes certain performance highlights for the periods stated.

- Per unit return on investment, calculated per year and compounded annually - six year 146%, one year 81%
- Production growth – fourth quarter production increased 35% from 15,273 boe/d in 2003 to 20,688 boe/d in 2004
- Per unit production growth - increased 32% per trust unit after adjusting for debt and bonuses
- Per unit funds from operations growth - increased 43% in the fourth quarter of 2004 compared to the fourth quarter of 2003
- Capital expenditures - acquisitions accounted for only 1% of the total capital, while the other 99% was invested to develop new oil and natural gas reserves
- Per unit reserve growth - the most conservative category, proved producing reserves, grew 29% per trust unit after adjusting for debt and bonuses
- Cost of new reserves (FD&A) - Proved $7.95/boe, Proved Plus Probable $7.38/boe (before future development capital)
- Recycle ratio - Proved 4.0, Proved Plus Probable 4.3 (before future development capital)
- Reserve replacement ratio - Proved 430%, Proved Plus Probable 460%
- Distributions per unit increased by 27% from the fourth quarter of 2003 while the payout ratio decreased from 50% to 44%. A total of $26.4 million or $0.57 per unit was distributed to unitholders in the fourth quarter of 2004.

Natural gas volumes recorded in thousand cubic feet (mcf) are converted to barrels of oil equivalent (boe) using the ratio of six (6) thousand cubic feet to one (1) barrel of oil (bbl).

	3 Months Ended Dec. 31		%	12 Months Ended Dec. 31		%
	2004	2003	Change	**2004**	2003	Change
Operations						
Production						
Natural gas (mcf/d)	**97,968**	73,013	*34%*	**88,842**	65,015	*37%*
Oil & NGLs (bbl/d)	**4,360**	3,104	*40%*	**3,882**	2,904	*34%*
Barrels of oil equivalent (boe/d @ 6:1)	**20,688**	15,273	*35%*	**18,689**	13,740	*36%*
Product prices						
Natural gas ($/mcf)	**7.58**	6.93	*9%*	**7.38**	7.51	*-2%*
Oil & NGLs ($/bbl)	**46.82**	35.22	*33%*	**42.66**	36.62	*16%*
Operating expenses ($/boe)	**1.03**	1.63	*-37%*	**1.05**	1.30	*-19%*
Transportation ($/boe)	**0.77**	0.56	*38%*	**0.70**	0.56	*25%*
Field netback ($/boe)	**32.90**	30.47	*8%*	**31.79**	31.43	*1%*
General & administrative expenses ($/boe)	**0.01**	0.10	*-90%*	**0.12**	0.18	*-33%*
Interest expense ($/boe)	**1.03**	0.80	*29%*	**1.01**	0.94	*7%*
Financial ($000, except per unit)						
Revenue	**87,127**	56,589	*54%*	**300,501**	216,931	*39%*
Royalties (net of ARTC)	**21,103**	10,688	*97%*	**71,089**	49,996	*42%*
Funds from operations	**60,334**	41,371	*46%*	**209,106**	151,407	*38%*
Funds from operations per unit	**1.30**	0.91	*43%*	**4.56**	3.41	*34%*
Cash distributions (1)	**26,443**	20,428	*29%*	**93,660**	40,856	*129%*
Cash distributions per unit	**0.57**	0.45	*27%*	**2.04**	0.90	*127%*
Percentage of funds from operations distributed	**44**	50	*-12%*	**45**	27	*67%*
Earnings before tax (2)	**12,888**	4,168	*209%*	**99,961**	54,423	*84%*
Future income and capital tax provisions (2)	**15,446**	(2,035)	*859%*	**26,179**	5,844	*348%*
Earnings (2)	**(2,558)**	6,203	*-141%*	**73,782**	48,579	*52%*
Earnings per diluted unit (2)	**(0.06)**	0.14	*-143%*	**1.61**	1.09	*48%*
Capital expenditures	**76,953**	43,763	*76%*	**230,774**	139,423	*66%*
Weighted average trust units outstanding	**46,247,011**	45,395,122	*2%*	**45,855,517**	44,430,031	*3%*
As at December 31						
Net debt (before future compensation expense)				**222,969**	162,466	*37%*
Unitholders' equity (2)				**205,849**	117,961	*75%*
Total assets (2)				**622,577**	416,146	*50%*

(1) The reorganization of Peyto into an income trust structure occurred effective July 1, 2003.
(2) Restated for the adoption of new accounting standards for asset retirement obligations.

Funds from operations

Management uses funds from operations to analyze the operating performance of its energy assets. In order to facilitate comparative analysis, funds from operations is defined throughout this report as earnings before bonus, non-cash and non-recurring expenses. We believe that funds from operations is an important parameter to measure the value of an asset when combined with reserve life. Funds from operations is not a measure recognized by Canadian generally accepted accounting principles ("GAAP") and does not have a standardized meaning prescribed by GAAP. Therefore, funds from operations, as defined by Peyto, may not be comparable to similar measures presented by other issuers, and investors are cautioned that funds from operations should not be construed as an alternative to net earnings, cash flow from operating activities or other measures of financial performance calculated in accordance with GAAP. Funds from operations cannot be assured and future distributions may vary.

	12 Months Ended Dec. 31	
	2004	2003
Earnings (2)	**73,782**	48,579
Items not requiring cash:		
Non-cash provision for bonuses	**15,945**	12,475
Future income tax expense (2)	**25,558**	5,290
Depletion, depreciation and accretion (2)	**40,880**	23,452
Non-recurring items:		
Trust reorganization costs	**-**	44,206
Market and reserves based bonuses	**52,941**	17,405
Funds from operations	**209,106**	151,407

(1) The reorganization of Peyto into an income trust structure occurred effective July 1, 2003.
(2) Restated for the adoption of new accounting standards for asset retirement obligations.

Reserves

Significant reserves and value growth occurred in 2004. This is reflective of Peyto's ability to grow its asset base as a trust while increasing its distributions to unitholders. The reserve growth in 2004 was a direct result of the capital invested during the year in developing our Deep Basin resource plays. The following table illustrates the change in reserve volumes and net present value of future cash flow, discounted at 8%, before income tax using variable pricing.

	As at December 31			
	2004	2003	% Change	% Change Debt Adjusted Per Unit
Reserves				
Gas (mmcf)				
Proved Producing	**334,981**	251,165	*33%*	*30%*
Total Proved	**437,078**	326,622	*34%*	*30%*
Proved + Probable Additional	**617,985**	494,148	*25%*	*22%*
Oil + NGL (mstb)				
Proved Producing	**15,166**	11,961	*27%*	*24%*
Total Proved	**19,182**	15,383	*25%*	*22%*
Proved + Probable Additional	**26,508**	22,713	*17%*	*14%*
BOE 6:1 (mstb)				
Proved Producing	**70,996**	53,822	*32%*	*29%*
Total Proved	**92,028**	69,820	*32%*	*29%*
Proved + Probable Additional	**129,506**	105,071	*23%*	*20%*
Net Present Value ($000)				
Discounted at 8%				
Proved Producing	**1,043,445**	665,490	*57%*	*53%*
Total Proved	**1,227,614**	813,320	*51%*	*47%*
Proved + Probable Additional	**1,542,687**	1,096,602	*41%*	*37%*

Note: Based on the Paddock Lindstrom & Associates report effective December 31, 2004. The Paddock Lindstrom and Associates Ltd. price forecast is available at www.padlin.com. The complete statement of reserves data and required reporting in compliance with NI 51-101 will be included in Peyto's Annual Information Form to be released in March 2005.

2004 Performance Ratios	**Proved Developed**	**Total Proved**	**Proved + Probable**
Reserve life index (years)			
2004 average production – 18,689 boe/d	11.2	13.5	19.0
Q4 2004 average production – 20,688 boe/d	10.2	12.2	17.2
Finding, development and acquisition costs ($/boe)			
Before future development capital	9.53	7.95	7.38
Including future development capital	9.77	9.46	9.55
Reserve replacement ratio	3.6	4.3	4.6
Recycle ratio			
Before future development capital	3.3	4.0	4.3
Including future development capital	3.3	3.4	3.3

- The reserve life index can be calculated using various methodologies. We believe the most accurate way to look at the reserve life index is by dividing the proved developed reserves by the actual fourth quarter average production. In our opinion, for comparative purposes the proved developed reserve life will provide the best measure of sustainability.
- Finding, development and acquisition ("FD&A") costs are used as a measure of capital efficiency and are calculated by dividing the capital costs for the period by the change in the reserves, including revisions, for the same period. Prior to NI 51-101, FD&A costs were calculated excluding future development capital ("FDC"). Both methods of calculating FD&A costs have been provided in order to facilitate comparisons with previous years.
- Peyto's reserve replacement ratio is calculated by dividing the yearly change in reserves, including revisions and before production by the actual annual production.
- The recycle ratio is calculated by dividing the field net back per boe by the FD&A costs for the period. In our opinion, it is the best overall measure of investment performance as it takes into consideration the value of the producing barrel and the cost to replace it. The new reserve policy has made the recycle ratio more meaningful for all the categories because the FD&A costs now include the future development capital.

National Instrument 51-101 Cautionary Statements

The Canadian Securities Administrators have implemented new standards of disclosure for reporting issuers engaged in upstream oil and gas activities effective December 31, 2003. The new disclosure standards referred to as National Instrument ("NI") 51-101 establish a regime of continuous disclosure for oil and gas companies and include specific reporting requirements.

- Peyto's year-end reserve report summarized herein is compliant with NI 51-101. Under NI 51-101's revised reserve definitions and evaluation standards, proved plus probable reserves represent a "best estimate" and hence for years prior to 2003, are compared to "established" reserves which were comprised of proved plus 50 percent of probable reserves.
- The term "boes" may be misleading particularly if used in isolation, a boe conversion ratio of 6 mcf : 1 barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
- It should not be assumed that the discounted net present values represent the fair market value of the reserves.
- The estimate of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.
- The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

Capital Expenditures

Net capital expenditures for 2004 totaled $230.8 million. Acquisitions accounted for 1% of the total capital, while the other 99% was invested to develop new oil and gas reserves. The following table summarizes capital expenditures for the year.

	2004		**2003**		**Since Inception**	
Capital Expenditures	**($000)**	**% of Total**	**($000)**	**% of Total**	**($000)**	**% of Total**
Land	3,975	*2*	3,063	*2*	15,389	*3*
Seismic	5,768	*2*	2,026	*1*	12,754	*2*
Drilling – Exploratory & Development	167,742	*73*	109,621	*79*	427,583	*70*
Production Equipment, Facilities & Pipelines	49,898	*22*	23,126	*17*	126,424	*21*
Acquisitions & Dispositions	3,307	*1*	1,500	*1*	30,856	*5*
Office Equipment	84	-	87	-	456	-
Total	230,774	*100*	139,423	*100*	613,462	*100*

The cost to drill, complete and tie in an average Peyto well has increased by 16% from 2003 to 2004 as illustrated in the following table:

Change in well makeup (diversification in depth & geographic location)	8%
Increase in service costs (both service rates and well materials)	15%
Improvement in efficiencies (reduced drilling times per meter)	(7%)
Total cost increase per well	16%

When Peyto commenced operations six years ago it had no cash flow to fund its capital expenditures and no land holdings in Alberta's Deep Basin area. We raised some initial seed capital and invested it into developing producing reserves in the Deep Basin. As a result of our exploration and development programs, we have managed to build a long life natural gas business with some of the lowest operating costs in today's energy sector. Our ability to effectively re-invest cash flow, debt and a small amount of equity in the development of new producing reserves has allowed us to generate high returns for our unitholders. This manufacturing approach takes raw material, undeveloped land, and turns it into a finished product, oil and natural gas production. As illustrated in the following table, cash flow generated from our investments has played a dominant role, while net equity has played a minor role in the overall funding of our capital expenditures.

	($000)	**% of Total**
Cash flow from projects found and developed by Peyto	359,002	58%
Net Equity (Equity issued of $166.0 million less Accumulated Distributions of $134.5 million)	31,491	5%
Net Debt	222,969	37%
Total Capital Expenditures	613,462	100%

Quarterly Review

Daily production for the three months averaged 98 mmcf of natural gas and 4,360 barrels of oil and natural gas liquids. Our production gains increased funds from operations from $41.4 million in 2003 to $60.3 million in 2004. Natural gas prices increased by 9% averaging $7.58 per mcf, oil and natural gas liquids prices increased 33% averaging $46.82 per barrel. The high heating value of our gas resulted in a 17% premium when converted from gigajoules at the AECO price hub to mcf at the plantgate. Operating costs averaged $1.03 per boe. Capital expenditures for the quarter totaled $77.0 million with drilling projects continuing at record levels.

Activity Update

To date in 2005, Peyto has drilled and cased 22 gross wells (16.8 net) and brought on-stream 22 gross (17.3 net) gas producers. Peyto's new Kakwa gas plant completed its first expansion in February, 2005 increasing capacity from 25 to 40 mmcf/d. Winter drilling and tie in projects are currently filling up this capacity. The newly constructed Peyto Cutbank gas plant became operational March 6, 2005 and is currently testing its 10 mmcf/d capacity. This facility will allow us to evaluate the production performance of this relatively new resource play. An expansion of our Sundance gas gathering system into the nearby Wildhay field has allowed us to begin producing from recent exploration successes. We continue to invest a high percentage of our capital in Sundance developing the deeper resource play. With 9 drilling and 7 completion rigs operating, Peyto is more active developing reserves and production in its core areas than ever before.

Hedging

Our hedging program worked well in 2004. We were able to protect our capital expenditures program and distributions while achieving a net gain of $1.7 million. We continue to believe that our best hedge is our foundation; low operating costs, low distribution ratio and long reserve life. All of these hedges combine to significantly reduce the Trust's sensitivity to changes in commodity prices.

Bonuses

When Peyto converted to a trust in July, 2003, new cash bonuses were put in place. The market based bonus replaced the old stock option plan. It was designed to be less costly, more transparent, more tax efficient to the unitholders and to provide better alignment with unitholders' objectives. The bonuses were established to reward employees for per unit market and reserve performance. Two thirds of the measurement was weighted towards the market performance while the other third was weighted towards the reserve performance. A more detailed discussion of our market and reserve based bonuses is available on our website.

The total bonuses paid in 2004, pursuant to the market and reserve based components, was $52.9 million (market component - $44.6 million; reserve component - $8.3 million). Total bonuses paid out by the trust in its first 18 months represent 4% of the total return that unitholders have realized in the market since conversion to a trust. "The size of these bonuses reflects the fact that the Peyto business model is working. In fact, it is working very well, and the people who made it work have accomplished a lot," said C. Ian Mottershead, Chairman of the Board. "The reserve based bonuses they received reflected a 30% increase in reserves per unit in 2004. Such an increase is very rare in the energy trust world. The market based bonuses reflect the three-fold advance in price that unitholders have enjoyed since Peyto became a trust less than two years ago."

Subsequent to the bonus payments, two private placements totaling 670,000 trust units were completed to Peyto employees and consultants for proceeds of $31.6 million. Over 97% of after tax bonus was reinvested by the employees back into units at an undiscounted 10 day weighted average price. All senior executives of Peyto have significant holdings of Peyto trust units. We are confident that Peyto's compensation program is aligned with the unitholders' objectives.

Distributions

The financial and operational results set out herein, continue to reflect the success of our business. Growth on a per unit basis has now allowed us to increase our distributions three times, or by 47% on aggregate, since the conversion to a trust in July 2003. Accumulated distributions now total $134.5 million or $2.94 per unit. During the fourth quarter, distributions represented 44% of funds from operations reflecting our high reinvestment ratio.

Effective with the February 2005 production month, cash distributions were increased by 16 percent or $0.03 per unit per month for a total of $0.22 per unit to be distributed on March 15, 2005.

On March 2, 2005, Peyto implemented a Distribution Reinvestment Plan ("DRIP"). The DRIP will be available starting with the March, 2005 distribution (paid on April 15, 2005) for unitholders of record on March 31, 2005. The DRIP provides a convenient mechanism for unitholders to reinvest their monthly cash distributions in additional trust units. The DRIP permits the purchase of Peyto trust units from treasury at a 5% discount to market price. Peyto will issue trust units from treasury at the 5% discount to satisfy the requirements of the DRIP, until it discloses otherwise. The DRIP is currently only available to Canadian resident unitholders. Residents of the United States may not participate in the DRIP Plan, as Peyto is not a registrant with the United States Securities and Exchange Commission. Details of the DRIP are available on Peyto's website www.peyto.com.

Outlook

Capital expenditures for 2005 are expected to be between $260 million and $300 million. The total amount of capital we invest in 2005 will ultimately be driven by the number and quality of projects we generate. The majority of our 2005 capital program will involve drilling, completion and tie-in of low risk development gas wells adjacent to existing infrastructure in Peyto's four core areas. These expenditures will be funded with a combination of funds from operations, working capital, equity and bank lines.

We have now completed our sixth consecutive year as an energy business. Our performance coupled with the foundation we have built clearly indicates that our business strategy works. If you are interested in learning more about our business and willing to invest some of your time to understand Peyto's past and future, we suggest that you visit the Peyto website at www.peyto.com where you will find a current presentation, financial and historical news releases and an updated insider trading summary.

Don T. Gray
President and Chief Executive Officer
March 9, 2005

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements of Peyto Energy Trust ("Peyto") for the years ended December 31, 2004 and 2003. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP").

The Trust was created by way of a Plan of Arrangement effective July 1, 2003 which reorganized Peyto Exploration & Development Corp. ("PEDC") from a corporate entity into a trust. Accordingly, the consolidated financial statements were reported on a continuity of interests basis. As such, comparative figures for the periods prior to July 1, 2003 are the financial results of PEDC. This discussion provides management's analysis of Peyto's historical financial and operating results and provides estimates of Peyto's future financial and operating performance based on information currently available. Actual results will vary from estimates and the variances may be significant. Readers should be aware that historical results are not necessarily indicative of future performance. This MD&A was prepared using information that is current as of March 8, 2005. Additional information about Peyto, including the most recently filed annual information form is available at www.sedar.com.

Certain information set forth in this Management's Discussion and Analysis, including management's assessment of the Trust's future plans and operations, contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond these parties' control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Peyto's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Peyto will derive therefrom. Peyto disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Management uses funds from operations to analyze the operating performance of its energy assets. In order to facilitate comparative analysis, funds from operations is defined throughout this report as earnings before bonus, non-cash and non-recurring expenses. We believe that funds from operations is an important parameter to measure the value of an asset when combined with reserve life. Funds from operations is not a measure recognized by Canadian generally accepted accounting principles ("GAAP") and does not have a standardized meaning prescribed by GAAP. Therefore, funds from operations, as defined by Peyto, may not be comparable to similar measures presented by other issuers, and investors are cautioned that funds from operations should not be construed as an alternative to net earnings, cash flow from operating activities or other measures of financial performance calculated in accordance with GAAP. Funds from operations cannot be assured and future distributions may vary.

All references are to Canadian dollars unless otherwise indicated. Natural gas volumes recorded in thousand cubic feet (mcf) are converted to barrels of oil equivalent (boe) using the ratio of six (6) thousand cubic feet to one (1) barrel of oil (bbl).

Recently, proposed new legislation to restrict foreign ownership was issued in draft form by the Department of Finance and has prompted all trusts, including Peyto, to review their capital structures. To the best of our knowledge, Peyto's foreign ownership level currently stands at approximately 28 percent, well below the level that would jeopardize Peyto's status as a mutual fund trust under this proposed legislation. A few trusts have reorganized, or propose to reorganize, their units into a dual class structure with the objective of restricting foreign ownership to less than 50 percent and therefore retaining their status as a mutual fund trust. Peyto is an active supporter of the efforts of the Canadian Association of Income Funds (CAIF) which is attempting to have the Department of Finance reconsider components of the proposed legislation. The Department of Finance has subsequently announced that they are taking more time to consider the proposed legislation. The Trust will continue to monitor these developments and if it is deemed appropriate, propose an amendment to its capital structure.

OVERVIEW

Peyto is a Canadian energy trust involved in the development and production of natural gas in Alberta's deep basin. As at December 31, 2004, we had total proved plus probable reserves of 129.5 million barrels of oil equivalent with a reserve life of 17.2 years as evaluated by our independent petroleum engineers. Our production is weighted as to approximately 80% natural gas and 20% natural gas liquids and oil.

The Peyto model is designed to deliver growth in its assets, production and income, all on a per unit basis. The model is built around three key principles:

- Using our technical expertise to achieve the best return on capital employed, through the development of internally generated drilling projects.
- A low payout ratio designed to efficiently fund our growing inventory of drilling projects.
- Having an asset base which is made up of high quality long life natural gas reserves.

Operating results over the last six years indicate that we have successfully implemented these principles. Our business model makes Peyto a truly unique energy trust.

ANNUAL FINANCIAL INFORMATION

The following is a summary of selected financial information of the Trust for the periods indicated. Reference should be made to the audited consolidated financial statements of the Trust, which are available at www.sedar.com.

Year Ended December 31 ($000 except per unit amount)	**2004**	2003	2002
Total revenue (before royalties)	**300,501**	216,931	92,709
Funds from operations	**209,106**	151,407	62,503
Per unit – basic	**4.56**	3.41	1.45
Per unit – diluted	**4.56**	3.41	1.41
Earnings (2)	**73,782**	48,579	28,605
Per unit – basic	**1.61**	1.09	0.67
Per unit – diluted	**1.61**	1.09	0.64
Total assets (2)	**622,577**	416,146	242,869
Total long-term debt	**180,000**	150,000	-
Cash distributions per unit	**2.04**	0.90	-

(1) The reorganization of Peyto into an income trust structure occurred effective July 1, 2003.
(2) Restated for the adoption of new accounting standards for asset retirement obligations.
(3) Variations between periods are set out in the following discussion.

QUARTERLY FINANCIAL INFORMATION

	2004				2003			
($000 except per unit amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total revenue (before royalties)	**87,127**	74,866	72,757	65,751	56,589	52,365	53,307	54,670
Funds from operations	**60,334**	54,211	48,548	46,012	41,371	35,882	36,791	37,309
Per unit – basic	**1.30**	1.19	1.06	1.01	0.91	0.79	0.85	0.86
Per unit – diluted	**1.30**	1.19	1.06	1.01	0.91	0.79	0.80	0.81
Earnings (loss) (2)	**(2,558)**	21,650	30,347	24,343	6,203	25,445	(1,600)	18,531
Per unit – basic	**(0.06)**	0.47	0.66	0.53	0.14	0.56	(0.04)	0.43
Per unit – diluted	**(0.06)**	0.47	0.66	0.53	0.14	0.56	(0.04)	0.40

(1) The reorganization of Peyto into an income trust structure occurred effective July 1, 2003.
(2) Restated for the adoption of new accounting standards for asset retirement obligations.
(3) Quarterly revenue remained relatively constant in 2003 as increases in production volumes were offset by decreasing average commodity prices. In 2004, revenue increased each quarter as our successful drilling program continued to increase production while commodity prices remained relatively flat throughout the year. Earnings were impacted by restructuring costs in the second quarter of 2003, cash bonus payments in the fourth quarters of 2003 and 2004 and future income tax in the fourth quarter of 2004.

RESULTS OF OPERATIONS

Production

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2004	2003	**2004**	2003
Natural gas (mmcf/d)	**97,968**	73,013	**88,842**	65,015
Oil & natural gas liquids (bbl/d)	**4,360**	3,104	**3,882**	2,904
Barrels of oil equivalent (boe/d)	**20,688**	15,273	**18,689**	13,740

Natural gas production averaged 97.9 mmcf/d in the fourth quarter of 2004, 34 percent higher than the 73.0 mmcf/d reported for the same period in 2003. Oil and natural gas liquids production averaged 4,360 bbl/d, an increase of 40 percent from 3,104 bbl/d reported in the prior year. Production for the year increased 36 percent from 13,740 boe/d to 18,689 boe/d. The production increases are directly attributable to Peyto's ongoing drilling program.

Commodity Prices

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2004	2003	**2004**	2003
Natural gas ($/mcf)	**7.23**	6.35	**7.19**	7.13
Hedging – gas ($/mcf)	**0.35**	0.58	**0.19**	0.38
Natural gas – after hedging ($/mcf)	**7.58**	6.93	**7.38**	7.51
Oil and natural gas liquids($/bbl)	**51.57**	35.22	**45.92**	36.62
Hedging – oil ($/bbl)	**(4.75)**	-	**(3.26)**	-
Oil and natural gas liquids – after hedging ($/bbl)	**46.82**	35.22	**42.66**	36.62
Total Hedging ($/boe)	**0.69**	2.75	**0.25**	1.80

Our natural gas price before hedging averaged $7.23/mcf during the fourth quarter of 2004, an increase of 14 percent from $6.35/mcf reported for the equivalent period in 2003. Oil and natural gas liquids prices averaged $51.57/bbl up 46 percent from $35.22/bbl a year earlier. Natural gas prices for the year were up 1 percent at $7.19/mcf and oil while natural gas liquids prices were up 25 percent at $45.92/bbl compared to 2003. Hedging activity for fiscal 2004 accounted for $0.25/boe of Peyto's price achieved. Expectations are for commodity prices to remain strong relative to historical pricing.

Revenue

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2004**	2003	**2004**	2003
Natural gas	**65,126**	42,666	**233,555**	169,097
Oil and natural gas liquids	**20,684**	10,059	**65,237**	38,811
Hedging gain	**1,317**	3,864	**1,709**	9,023
Total revenue	**87,127**	56,589	**300,501**	216,931

For the three months ended December 31, 2004, gross revenue increased 54 percent to $87.1 million from $56.6 million for the same period in 2003. Revenue for the year was up 39 percent primarily as a result of increased production volumes as detailed in the following table:

	Three Months ended December 31				Twelve Months ended December 31			
	2004	2003	Change	**$million**	2004	2003	Change	**$million**
Natural gas								
Volume (mcf/d)	97,968	73,013	24,955		88,842	65,015	23,827	
Volume (mcf)	9,013,062	6,717,165	2,295,897	**15.9**	32,516,227	23,730,361	8,785,866	**66.0**
Price ($/mcf)	7.58	6.93	0.65	**5.8**	7.38	7.51	(0.13)	**(4.2)**
Oil & NGL								
Volume (bbl/d)	4,360	3,104	1,256		3,882	2,904	978	
Volume (bbl)	401,112	285,572	115,540	**4.1**	1,420,909	1,059,978	360,931	**13.2**
Price ($/bbl)	46.82	35.22	11.60	**4.7**	42.66	36.62	6.04	**8.6**
Total revenue ($million)	87.1	56.6	30.5	**30.5**	300.5	216.9	83.6	**83.6**

Royalties

We pay royalties to the owners of the mineral rights with whom we hold leases, including the provincial government of Alberta. Alberta gas crown royalties are invoiced on the Crown's share of production based on a monthly established Alberta Reference Price. The Alberta Reference Price is a monthly weighted average price of gas consumed in Alberta and gas exported from Alberta reduced for transportation and marketing allowances.

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2004	2003	**2004**	2003
Royalties, net of ARTC ($000)	**21,103**	10,688	**71,089**	49,996
% of sales	**24**	19	**24**	23
$/boe	**11.08**	7.61	**10.39**	9.97

For the fourth quarter of 2004, royalties averaged $11.08/boe or approximately 24 percent of Peyto's total petroleum and natural gas sales. Year to date royalties were 24 percent of sales in 2004 compared to 23 percent in 2003. The royalty rate expressed as a percentage of sales, will fluctuate from period to period due to the fact that the Alberta Reference Price can differ significantly from the commodity prices obtained by the Trust.

Operating Costs & Transportation

The Trust's operating expenses include all costs with respect to day-to-day well and facility operations. Processing and gathering income related to joint venture and third party gas reduces operating expenses.

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2004	2003	**2004**	2003
Operating costs ($000)				
Field expenses	**3,984**	3,097	**12,187**	9,972
Processing and gathering income	**(2,031)**	(806)	**(4,977)**	(3,466)
Total operating costs	**1,953**	2,291	**7,210**	6,506
$/boe	**1.03**	1.63	**1.05**	1.30
Transportation	**1,456**	789	**4,767**	2,818
$/boe	**0.77**	0.56	**0.70**	0.56

Operating costs were $1.9 million in the fourth quarter compared to $2.3 million during the same period a year earlier. On a unit-of-production basis, operating costs averaged $1.03/boe in the fourth quarter of 2004 compared to $1.63/boe for the fourth quarter of 2003. Operating costs for the year averaged $1.05/boe in 2004 compared to $1.30/boe in 2003.

Netbacks

Operating netbacks represent the profit margin associated with the production and sale of petroleum and natural gas. The primary factors that produce Peyto's strong netbacks are a low cost structure and the high heat content of our natural gas that results in higher commodity prices.

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($/boe)	**2004**	2003	**2004**	2003
Sale Price	**45.78**	40.27	**43.93**	43.26
Less:				
Royalties	**11.08**	7.61	**10.39**	9.97
Operating costs	**1.03**	1.63	**1.05**	1.30
Transportation	**0.77**	0.56	**0.70**	0.56
Operating netback	**32.89**	30.47	**31.79**	31.43
General and administrative	**0.01**	0.10	**0.12**	0.18
Interest on long-term debt	**1.03**	0.80	**1.01**	0.94
Capital tax	**0.16**	0.12	**0.09**	0.11
Cash netback	**31.69**	29.45	**30.57**	30.20

General and Administrative Expenses

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2004	2003	**2004**	2003
G&A expenses ($000)	**1,451**	783	**4,593**	3,115
Overhead recoveries	**(1,441)**	(636)	**(3,790)**	(2,204)
Net G&A expenses	**10**	147	**803**	912
$/boe	**0.01**	0.10	**0.12**	0.18

General and administrative expenses before overhead recoveries increased to $1.5 million in the fourth quarter of 2004, as compared to $0.8 million for the same period in 2003 primarily due to staffing increases required to manage our active drilling program and increasing property base. Net of overhead recoveries associated with our capital expenditures program, general and administrative costs decreased to $0.01 per boe from $0.10 per boe in 2003. General and administrative expenses for 2004 averaged $0.12/boe in 2004 compared to $0.18 in 2003.

Interest Expense

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2004	2003	**2004**	2003
Interest expense ($000)	**1,964**	1,130	**6,905**	4,739
$/boe	**1.03**	0.80	**1.01**	0.94

2004 interest expense was $6.9 million or $1.01/boe compared to $4.7 million or $0.94/boe a year earlier. During 2004, average debt levels increased to partially fund Peyto's capital expenditures program. Interest rates continue to be favourable and are not expected to increase substantially in the short-term.

Depletion, Depreciation and Accretion

The 2004 provision for depletion, depreciation and accretion totaled $40.9 million as compared to $23.5 million in 2003. On a unit-of-production basis, depletion, depreciation and accretion costs averaged $5.98/boe as compared to $4.68/boe in 2003. Increases or decreases in the depletion rate on a unit-of-production basis are influenced by the reserves added through Peyto's drilling program. As set out under the section "Changes in Accounting Policies", Peyto adopted the CICA pronouncement with respect to Asset Retirement Obligations, effective January 1, 2004.

Income Taxes

The current provision for future income tax increased to $25.6 million in 2004 from $5.3 million in 2003. Included in the 2004 provision was an amount of $15.1 million recorded in the fourth quarter. Our trust structure is unique in that it was designed to provide for discretion at the operating trust level to distribute taxable income to the Trust. Given the significant level of capital expenditures incurred by Peyto in the fourth quarter, the operating trust had additional resource pool deductions available for use which give rise to temporary differences which increased future income taxes in the fourth quarter. Unitholders benefit as the use of these resource pools increases the tax free return of capital component of the cash distributions.

HEDGING

Commodity Price Risk Management

The Trust is a party to certain off balance sheet derivative financial instruments, including fixed price contracts. The Trust enters into these contracts with well established counter-parties for the purpose of protecting a portion of its future revenues from the volatility of oil and natural gas prices. During 2004, we recorded a hedging gain of $1.7 million as compared to $9.0 million in 2003. As set out under the section "Changes in Accounting Policies", we have adopted, effective January 1, 2004, the new CICA Accounting Guideline 13 with respect to Hedging Relationships. A summary of contracts outstanding in respect of the hedging activities are as follows:

Crude Oil - Period Hedged	Type	Daily Volume	Price (CAD)
January 1 to March 31, 2005	Fixed price	500 bbl	$50.85/bbl
January 1 to March 31, 2005	Fixed price	200 bbl	$50.65/bbl
January 1 to March 31, 2005	Fixed price	200 bbl	$53.25/bbl
January 1 to March 31, 2005	Fixed price	300 bbl	$57.50/bbl
April 1 to June 30, 2005	Fixed price	500 bbl	$48.85/bbl
April 1 to June 30, 2005	Fixed price	200 bbl	$49.25/bbl
April 1 to June 30, 2005	Fixed price	200 bbl	$51.85/bbl
April 1 to June 30, 2005	Fixed price	300 bbl	$57.35/bbl
April 1 to June 30, 2005	Fixed price	200 bbl	$63.70/bbl
July 1 to September 30, 2005	Fixed price	250 bbl	$54.08/bbl
July 1 to September 30, 2005	Fixed price	350 bbl	$56.08/bbl
July 1 to September 30, 2005	Fixed price	200 bbl	$59.02/bbl
July 1 to September 30, 2005	Fixed price	200 bbl	$53.12/bbl
July 1 to September 30, 2005	Fixed price	100 bbl	$54.35/bbl
July 1 to September 30, 2005	Fixed price	200 bbl	$62.22/bbl
October 1 to December 31, 2005	Fixed price	300 bbl	$54.35/bbl
October 1 to December 31, 2005	Fixed price	250 bbl	$57.52/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$52.07/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$53.15/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$55.20/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$60.50/bbl
January 1 to March 31, 2006	Fixed price	300 bbl	$53.85/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$54.58/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$57.65/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$58.90/bbl

Natural Gas Period Hedged	Type	Daily Volume	Floor (CAD)	Ceiling (CAD)
Nov. 1, 2004 to March 31, 2005	Costless collar	10,000 GJ	$5.50/GJ	$8.00/GJ
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$6.65/GJ	
Nov. 1, 2004 to March 31, 2005	Costless collar	10,000 GJ	$6.00/GJ	$7.65/GJ
Nov. 1, 2004 to March 31, 2005	Fixed price	10,000 GJ	$6.97/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$6.95/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.08/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.14/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.56/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.75/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.50/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.71/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.70/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.80/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.45/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.55/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.70/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.00/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.27/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.42/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.65/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.80/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.90/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.01/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.11/GJ	
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.40/GJ	
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.50/GJ	
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.60/GJ	
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.70/GJ	
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.80/GJ	
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.91/GJ	
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.01/GJ	

Commodity Price Sensitivity

Our low operating costs, low distribution ratio and long reserve life reduce our sensitivity to changes in commodity prices.

Currency Risk Management

The Trust is exposed to fluctuations in the Canadian/US dollar exchange ratio since our natural gas and oil sales are effectively priced in US dollars and converted to Canadian dollars. Currently we have not entered into any agreements to manage this specific risk.

Interest Rate Risk Management

The Trust is exposed to interest rate risk in relation to interest expense on its revolving demand facility. Currently we have not entered into any agreements to manage this risk. At December 31, 2004, the increase or decrease in earnings for each 1% change in interest rate paid on the outstanding revolving demand loan amounts to approximately $1.8 million per annum.

LIQUIDITY AND CAPITAL RESOURCES

Funds from Operations

	Three Months ended Dec. 31		Twelve Months	
($000)	**2004**	2003	**2004**	2003
Earnings [(2)]	**(2,558)**	6,203	**73,782**	48,579
Items not requiring cash:				
Non-cash provision for bonuses	**(15,966)**	12,475	**15,945**	12,475
Future income tax expense [(2)]	**15,140**	(2,208)	**25,558**	5,290
Depletion, depreciation & accretion [(2)]	**10,777**	7,496	**40,880**	23,452
Non-recurring items:				
Market and reserves based bonuses	**52,941**	17,405	**52,941**	17,405
Trust reorganization costs	**-**	-	**-**	44,206
Funds from operations	**60,334**	41,371	**209,106**	151,407

(1) The reorganization of Peyto into an income trust structure occurred effective July 1, 2003.
(2) Restated for the adoption of new accounting standards for asset retirement obligations.

For the quarter ended December 31, 2004, funds from operations totaled $60.3 million or $1.30 per unit, representing a 46 percent increase from the $41.4 million, or $0.91 per diluted unit during the same period in 2003. For fiscal 2004 funds from operations totaled $209.1 million or $4.56 per unit in 2004 compared to $151.4 million or $3.41 per unit in 2003. Peyto's policy is to distribute approximately 50% of funds from operations to unitholders while retaining the balance to fund its growth oriented capital expenditures program. Our earnings and cash flow are highly sensitive to changes in commodity prices, exchange rates and other factors that are beyond our control. Current volatility in commodity prices creates uncertainty as to our funds from operations and capital expenditure budget. Accordingly, we assess results throughout the year and revise our operational plans as necessary to reflect the most current information.

Our revenues will be impacted by drilling success and production volumes as well as external factors such as the market prices for natural gas and crude oil and the exchange rate of the Canadian dollar relative to the US dollar.

Bank Debt

We have an extendible revolving term credit facility with a syndicate of financial institutions in the amount of $300 million including a $280 million revolving facility and a $20 million operating facility. Available borrowings are limited by a borrowing base, which is based on the value of petroleum and natural gas assets as determined by the lenders. The loan is reviewed annually and may be extended at the option of the lender for an additional 364 day period. If not extended, the revolving facility will automatically convert to a one year and one day non-revolving term loan. The loan has therefore been classified as long-term on the balance sheet.

At December 31, 2004, $180 million was drawn under the facility. Working capital liquidity is maintained by drawing from and repaying the unutilized credit facility as needed. At December 31, 2004, we had a working capital deficit of $65.3 million.

We believe that funds generated from our operations, together with borrowings under our credit facility and proceeds, if any, from equity issued will be sufficient to finance our current operations and planned capital expenditure program. In 2004 capital expenditures totaled $230.8 million, primarily all of which were discretionary focused on exploration, development and acquisition activity. The majority of these expenditures were employed to drill, complete and tie-in natural gas wells adjacent to Peyto's existing infrastructure. Peyto has the flexibility to match planned capital expenditures to actual cash flow.

Capital

As at December 31, 2004, 47.7 million trust units were outstanding. On December 31, 2004 the Trust completed a private placement of 582,500 trust units to employees and consultants for net proceeds of $27.1 million. The trust units were issued on January 4, 2005. On February 15, 2005 an additional 87,500 trust units were issued to employees and consultants at a price of $51.43 per trust unit. As at March 8, 2005, 48.4 million trust units were outstanding.

Authorized: Unlimited number of voting trust units
Issued and Outstanding:

Trust Units (no par value)	**Number of Shares/Units**	**Amount $**
Balance, December 31, 2002	43,418,188	19,230,677
Share issue costs, net of tax	-	(10,615)
Exercise of stock options	33,334	134,336
Shares converted to trust units	(43,451,522)	(19,354,398)
Trust units issued on conversion of shares	43,451,522	19,354,398
Trust units issued by private placement	1,943,600	29,873,132
Balance, December 31, 2003	45,395,122	49,227,530
Trust units issued by private placement	330,150	9,013,095
Trust units issued	2,000,000	85,300,000
Trust unit issue costs	-	(4,587,599)
Balance, December 31, 2004	47,725,272	138,953,026

Market & Reserves Based Bonuses

The Trust awards bonuses to employees and key consultants. The bonus structure is comprised of market and reserves based components.

Under the reserves based component, the bonus pool will be initially comprised of 3% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity and distributions, of proved producing reserves calculated using a constant price at December 31 of the current year and a discount rate of 8%.

($ million except unit values)	2003	2004	Change
Net present value of proved producing reserves @ 8% based on constant external engineer 2005 price forecast	880.0	1,138.0	258.0
Net debt before bonus	(162.5)	(197.1)	(34.6)
2004 distributions	(93.7)	-	93.7
Net value	623.8	940.9	317.1
Equity adjustment factor*			88%
Equity adjusted increase in value			277.8
2004 Reserves based bonus @ 3%			8.3

*Equity adjustment factor is calculated as the percent increase in value per unit divided by the total percent increase in value

Under the market based component, rights with a three year vesting period are allocated to employees and key consultants. The number of rights outstanding at any time is not to exceed 7% of the total number of trust units outstanding. At December 31 of each year, all vested rights are automatically cancelled and, if applicable, paid out in cash. The bonus is calculated as the number of vested rights multiplied by the total of the market appreciation (over the price at the date of grant) and associated distributions of a trust unit for that period. A tax factor of 1.333 is then applied to determine the amount of the bonus to be paid. The market based bonus for 2004 was based on 1.0 million vested rights at an average grant price of $16.81, average cumulative distributions of $2.73 and the five day weighted average closing price of $47.54 (2003 – 1.0 million rights, average grant price of $15.37, cumulative distributions of $0.90 per unit and five day weighted average closing price of $27.36).

The total amount expensed under these plans was as follows:

	2004 $	2003 $
Market based bonus	**44,607,873**	17,405,380
Reserves based bonus	**8,333,000**	-
Total	**52,940,873**	17,405,380

Compensation costs as at December 31, 2004 related to 1.6 million non-vested rights with an average grant price of $20.76 was $63.1 million of which a non-cash provision for future compensation expense of $12.5 million was recorded at December 31, 2003 and an additional $15.9 million was recorded in 2004.

Capital Expenditures

Net capital expenditures for 2004 totaled $230.8 million. Exploration and development related activity represented $173.5 million or 75% of the total, while expenditures on facilities, gathering systems and equipment totaled $49.9 million or 22% of the total. The following table summarizes capital expenditures for the year.

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2004**	2003	**2004**	2003
Land	**772**	1,436	**3,975**	3,063
Seismic	**3,314**	890	**5,768**	2,026
Drilling – Exploratory & Development	**61,007**	31,915	**167,742**	109,621
Production Equipment, Facilities & Pipelines	**11,799**	8,377	**49,898**	23,126
Acquisitions & Dispositions	**52**	1,123	**3,307**	1,500
Office Equipment	**9**	22	**84**	87
Total capital expenditures	**76,953**	43,763	**230,774**	139,423

Cash Distributions

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2004	2003	**2004**	2003
Funds from operations ($000)	**60,334**	41,371	**209,106**	151,407
Distributions ($000)	**26,443**	20,428	**93,660**	40,856
Distributions per unit ($)	**0.57**	0.45	**2.04**	0.90
Payout ratio (%)	**44**	50	**45**	27

(1) The reorganization of Peyto into an income trust structure occurred effective July 1, 2003.

Peyto's strategy is to distribute approximately 50 percent of funds from operations to our unitholders on a monthly basis with the balance being withheld to fund capital expenditures. Management is prepared to adjust the payout levels to balance desired distributions with our requirement to maintain an appropriate capital structure. For Canadian income tax purposes distributions made are considered a combination of income and return of capital. The portion that is return of capital reduces the adjusted cost base of the units.

Contractual Obligations

The Trust is committed to payments under operating leases for office space as follows:

	$
2005	417,790
2006	363,780
2007	363,780
	1,145,350

GUARANTEES/OFF-BALANCE SHEET ARRANGEMENTS

The Trust is a party to certain off balance sheet derivative financial instruments, including fixed price contracts as discussed further in the Hedging section.

RELATED PARTY TRANSACTIONS

A director of the Trust is a partner of a law firm that was paid $430,705 for legal services for the year ended December 31, 2004 (December 31, 2003 - $866,379). The fees charged were based on standard rates and time spent on matters pertaining to the Trust and its subsidiaries.

INCOME TAXES

The following sets out a general discussion of the Canadian and US tax consequences of holding Peyto units as capital property. The summary is not exhaustive in nature and is not intended to provide legal or tax advice. Unitholders or potential Unitholders should consult their own legal or tax advisors as to their particular tax consequences.

Canadian Taxpayers

The Trust qualifies as a mutual fund trust under the *Income Tax Act* (Canada) and, accordingly, Trust units are qualified investments for RRSPs, RRIFs, RESPs and DPSPs. Each year, the Trust is required to file an income tax return and any taxable income of the Trust is allocated to unitholders.

Unitholders are required to include in computing income their pro-rata share of any taxable income earned by the Trust in that year. An investor's adjusted cost base (ACB) in a trust unit equals the purchase price of the unit less any non-taxable cash distributions received from the date of acquisition. To the extent the unitholders' ACB is reduced below zero, such amount will be deemed to be a capital gain to the unitholder and the unitholders' ACB will be brought to nil.

During the year of 2004, the Trust paid distributions to the unitholders in the amount of $93.7 million in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit
January 2004	January 30, 2004	February 16, 2004	$0.15
February 2004	February 27, 2004	March 15, 2004	$0.15
March 2004	March 31, 2004	April 15, 2004	$0.15
April 2004	April 30, 2004	May 14, 2004	$0.17
May 2004	May 31, 2004	June 15, 2004	$0.17
June 2004	June 30, 2004	July 15, 2004	$0.17
July 2004	July 30, 2004	August 16, 2004	$0.17
August 2004	August 31, 2004	September 15, 2004	$0.17
September 2004	September 30, 2004	October 15, 2004	$0.17
October 2004	October 29, 2004	November 15, 2004	$0.19
November 2004	November 30, 2004	December 15, 2004	$0.19
December 2004	December 31, 2004	January 14, 2005	$0.19
			$2.04

US Taxpayers

US unitholders who receive cash distributions are subject to a 15 percent Canadian withholding tax, applied to the taxable portion of the distributions as computed under Canadian tax law. US taxpayers may be eligible for a foreign tax credit with respect to Canadian withholding taxes paid.

The taxable portion of the cash distributions, if any, is determined by the Trust in relation to its current and accumulated earnings and profit using US tax principles. The taxable portion so determined, is considered to be a dividend for US tax purposes.

The non-taxable portion of the cash distributions is a return of the cost (or other basis). The cost (or other basis) is reduced by this amount for computing any gain or loss from disposition. However, if the full amount of the cost (or other basis) has been recovered, any further non-taxable distributions should be reported as a gain.

US unitholders are advised to seek legal or tax advice from their professional advisors.

RISK MANAGEMENT

Investors who purchase our units are participating in the net funds from operations from a portfolio of western Canadian crude oil and natural gas producing properties. As such, the funds from operations paid to investors and the value of the units are subject to numerous risks inherent in the oil and natural gas industry.

Our expected funds from operations depends largely on the volume of petroleum and natural gas production and the price received for such production, along with the associated operating costs. The price we receive for our oil depends on a number of factors, including West Texas Intermediate oil prices, Canadian/US currency exchange rates, quality differentials and Edmonton par oil prices. The price we receive for our natural gas production is primarily dependent on current Alberta market prices. Peyto has an ongoing commodity price risk management policy that provides for downside protection on a portion of its future production while allowing access, in certain cases, to the upside price movements.

Although our focus is on our internally generated drilling programs, any acquisition of oil and natural gas assets depends on our assessment of value at the time of acquisition. Incorrect assessments of value can adversely affect distributions to unitholders and the value of the units. We employ experienced staff on our team and perform appropriate levels of due diligence on our analysis of acquisition targets, including a detailed examination of reserve reports; if appropriate, re-engineering of reserves for a large portion of the properties to ensure the results are consistent; site examinations of facilities for environmental liabilities; detailed examination of balance sheet accounts; review of contracts; review of prior year tax returns and modeling of the acquisition to attempt to ensure accretive results to the unitholders.

Inherent in development of the existing oil and gas reserves are the risks, among others, of drilling dry holes, encountering production or drilling difficulties or experiencing high decline rates in producing wells. To minimize these risks, we employ experienced staff to evaluate and operate wells and utilize appropriate technology in our operations. In addition, we use prudent work practices and procedures, safety programs and risk management principles, including insurance coverage against potential losses.

The value of our Trust units is based on among other things, the underlying value of the oil and natural gas reserves. Geological and operational risks can affect the quantity and quality of reserves and the cost of ultimately recovering those reserves. Lower oil and gas prices increase the risk of write-downs on our oil and gas property investments. In order to mitigate this risk, our proven and probable oil and gas reserves are evaluated each year by a firm of independent reservoir engineers. The reserves committee of the Board of Directors reviews and approves the reserve report.

Our access to markets may be restricted at times by pipeline or processing capacity. We minimize these risks by controlling as much of our processing and transportation activities as possible and ensuring transportation and processing contracts are in place with reliable cost efficient counter-parties.

The petroleum and natural gas industry is subject to extensive controls, regulatory policies and income and resource taxes imposed by various levels of government. These regulations, controls and taxation policies are amended from time to time. We have no control over the level of government intervention or taxation in the petroleum and natural gas industry. However, we operate in such a manner to ensure that we are in compliance with all applicable regulations and are able to respond to changes as they occur.

The petroleum and natural gas industry is subject to both environmental regulations and an increased environmental awareness. We have reviewed our environmental risks and are, to the best of our knowledge, in compliance with the appropriate environmental legislation and have determined that there is no current material impact on our operations.

We are subject to financial market risk. In order to maintain substantial rates of growth, we must continue reinvesting in, drilling for or acquiring petroleum and natural gas. Our capital expenditure program is funded primarily through funds from operations, debt and when appropriate, through the issuance of equity.

CRITICAL ACCOUNTING ESTIMATES

Reserve Estimates

Estimates of oil and natural gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent to the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is an analytical process of estimating underground accumulations of oil and natural gas that can be difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas prices, future royalties and operating costs, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk recovery, and estimates of the future net cash flows expected there from may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Trust's oil and natural gas properties and the rate of depletion of the oil and natural gas properties. Actual production, revenues and expenditures with respect to the Trust's reserves will likely vary from estimates, and such variances may be material.

The Trust's estimated quantities of proved and probable reserves at December 31, 2004 were audited by independent petroleum engineers Paddock Lindstrom & Associates Ltd. Paddock has been evaluating reserves in this area and for Peyto for 6 consecutive years.

Depletion and Depreciation Estimate

We follow the full cost method of accounting for petroleum and natural gas operations whereby all costs of exploring for and developing petroleum and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical costs, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells and overhead charges directly related to acquisition, exploration and development activities.

All costs of exploring for and developing petroleum and natural gas reserves, together with the costs of production equipment, are depleted and depreciated on the unit-of-production method based on estimated gross proven reserves. Petroleum and natural gas reserves and production are converted into equivalent units based upon estimated relative energy content (6 mcf to 1 barrel of oil).

Costs of acquiring unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment has occurred. When proven reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations.

Full Cost Accounting Ceiling Test

The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The ceiling test is based on estimates of proved reserves, production rates, estimated future petroleum and natural gas prices and costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion and depreciation expense.

Asset Retirement Obligation

The asset retirement obligation is estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonment and reclamation discounted at a credit adjusted risk free rate. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Future Market Based Bonus

The provision for future market based bonus is estimated based on current market conditions, distribution history and on the assumption that all outstanding rights will be paid out according to the vesting schedule. The conditions at the time of vesting could vary significantly from the current conditions and may have a material effect on the calculation.

Income Taxes

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

CHANGES IN ACCOUNTING POLICIES

Full Cost Accounting

The CICA issued Accounting Guideline 16 which replaces Accounting Guideline 5, Full Cost Accounting in the Oil and Gas Industry. The guideline is effective for fiscal years beginning on or after January 1, 2004 and is to be accounted for on a prospective basis. The most significant change is the modification of the ceiling test to be consistent with CICA Section 3063, Impairment of Long-lived Assets. The new guideline limits the carrying value of oil and gas properties to their fair value. There is no write down of our property, plant and equipment under the new method as of December 31, 2004.

Asset Retirement Obligations

The CICA issued Section 3110 Asset Retirement Obligations to harmonize Canadian GAAP with Financial Accounting Standards Board Statement No. 143. The section replaces previous guidance on future removal and site restoration costs and is effective for fiscal years beginning on or after January 1, 2004. The asset retirement obligation liability will initially be measured at fair value, which is the discounted future value of the liability. The liability accretes until the obligation is settled. The fair value is capitalized as part of the related asset and is depleted over the useful life of the asset. Prior periods have been restated in accordance with the new standard.

Hedging Relationships

The Canadian Institute of Chartered Accountants (CICA) issued Accounting Guideline 13 – Hedging Relationships, which deals with the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The guideline establishes conditions for applying hedge accounting. The guideline is effective for fiscal years beginning on or after July 1, 2003. Where hedge accounting does not apply, any changes in the mark to market values of the option contracts relating to a financial period can either reduce or increase net income and net income per trust unit for that period. We enter into numerous financial instruments to manage our commodity price risk that qualify as hedges under the new accounting guideline. Effective January 1, 2004, we have elected to apply hedge accounting to all of our financial instruments.

Continuous Disclosure Obligations

Effective March 31, 2004, the Trust and all reporting issuers in Canada have become subject to new disclosure requirements pursuant to National Instrument 51-102 "Continuous Disclosure Obligations". This new instrument proposes shorter reporting periods for filing of annual and interim financial statements, MD&A and Annual Information Form (AIF). The instrument also requires enhanced disclosure in the annual and interim financial statements, MD&A and AIF. Under this new instrument, it will no longer be mandatory for the Trust to mail annual and interim financial statements and MD&A to unitholders, but rather these documents will be provided on an "as requested" basis. The Trust continues to assess the implications of this new instrument which has been implemented in 2004.

ADDITIONAL INFORMATION

Additional information relating to Peyto Energy Trust can be found on SEDAR at www.sedar.com and www.peyto.com.

Quarterly Information

	2004				2003
	Q4	Q3	Q2	Q1	Q4
Operations					
Production					
Natural gas (mcf/d)	**97,968**	91,782	87,753	78,597	73,013
Oil & NGLs (bbl/d)	**4,360**	3,967	3,918	3,315	3,104
Barrels of oil equivalent (boe/d @ 6:1)	**20,688**	19,264	18,544	16,414	15,273
Average product prices					
Natural gas ($/mcf)	**7.58**	7.00	7.32	7.63	6.93
Oil & natural gas liquids ($/bbl)	**46.82**	43.13	40.06	39.59	35.22
Average operating expenses ($/boe)	**1.03**	1.08	1.04	1.08	1.63
Average transportation costs ($/boe)	**0.77**	0.68	0.74	0.58	0.56
Field netback ($/boe)	**32.90**	31.72	30.14	32.32	30.47
General & administrative expense ($/boe)	**0.01**	0.05	0.30	0.14	0.10
Interest expense ($/boe)	**1.03**	1.03	0.99	0.97	0.80
Financial ($000 except per unit)					
Revenue	**87,127**	74,866	72,757	65,751	56,589
Royalties (net of ARTC)	**21,103**	15,529	18,904	15,553	10,688
Funds from operations	**60,334**	54,211	48,548	46,012	41,371
Funds from operations per unit	**1.30**	1.19	1.06	1.01	0.91
Cash distributions	**26,443**	23,320	23,320	20,576	20,428
Cash distributions per unit	**0.57**	0.51	0.51	0.45	0.45
Percentage of funds from operations distributed	**44%**	43%	48%	45%	50%
Earnings*	**(2,558)**	21,650	30,347	24,343	6,203
Earnings per diluted unit*	**(0.06)**	0.47	0.66	0.53	0.14
Capital expenditures	**76,953**	55,565	37,067	61,187	43,763
Weighted average trust units outstanding	**46,247,011**	45,725,272	45,725,272	45,721,644	45,395,122

*Note: restated for the adoption of new accounting standards for asset retirement obligations

Auditors' Report

To the Unitholders of
Peyto Energy Trust:

We have audited the consolidated balance sheet of **Peyto Energy Trust** as at December 31, 2004 and the consolidated statements of earnings and accumulated earnings and cash flows for the year then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2004 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The financial statements for the year ended December 31, 2003 were reported upon by another firm of Chartered Accountants who expressed an opinion without reservation in their auditors' report dated February 13, 2004.

Deloitte & Touche LLP

Calgary, Alberta
March 4, 2005

Chartered Accountants

Peyto Energy Trust

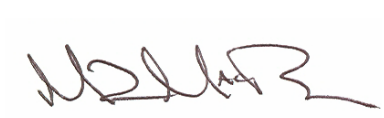
CONSOLIDATED BALANCE SHEETS

As at December 31,

	2004	2003 (restated – Notes 2 & 5)
	$	$
Assets		
Current		
Cash	**-**	20,591,218
Accounts receivable *(Note 12)*	**58,992,005**	41,110,278
Due from private placements *(Note 6)*	**27,080,066**	9,013,095
Prepaid expenses and deposits	**5,262,778**	5,132,281
	91,334,849	75,846,872
Property, plant and equipment *(Notes 3 and 4)*	**531,241,786**	340,298,794
	622,576,635	416,145,666
Liabilities and Unitholders' Equity		
Current		
Accounts payable and accrued liabilities	**124,753,199**	81,426,984
Capital taxes payable	**483,081**	76,726
Cash distributions payable	**9,067,811**	6,809,268
Provision for future market based bonus *(Note 9)*	**22,298,937**	7,515,119
	156,603,028	95,828,097
Long-term debt *(Note 4)*	**180,000,000**	150,000,000
Provision for future market based bonus *(Note 9)*	**6,121,097**	4,959,979
Asset retirement obligations *(Note 5)*	**3,328,834**	2,279,411
Future income taxes *(Note 11)*	**70,675,002**	45,116,705
	260,124,933	202,356,095
Unitholders' equity		
Unitholders' capital *(Note 6)*	**138,953,026**	49,227,530
Units to be issued *(Note 6)*	**27,052,850**	9,013,095
Accumulated earnings	**174,358,093**	100,576,459
Accumulated cash distributions *(Note 7)*	**(134,515,295)**	(40,855,610)
	205,848,674	117,961,474
	622,576,635	416,145,666

See accompanying notes

On behalf of the Board:



Director

Director

Peyto Energy Trust

CONSOLIDATED STATEMENTS OF EARNINGS AND ACCUMULATED EARNINGS

For the years ended December 31,

	2004	2003 (restated – Notes 2 & 5)
	$	$
Revenue		
Petroleum and natural gas sales, net	**229,412,031**	166,934,948
Expenses		
Operating *(Note 8)*	**7,210,155**	6,505,575
Transportation	**4,766,755**	2,818,022
General and administrative	**803,458**	911,503
Market and reserves based bonus *(Note 9)*	**52,940,873**	17,405,380
Future market based bonus provision *(Note 9)*	**15,944,936**	12,475,098
Interest	**6,904,809**	4,738,866
Trust reorganization *(Note10)*	**-**	44,206,442
Depletion, depreciation and accretion *(Note 5)*	**40,879,937**	23,451,512
	129,450,923	112,512,398
Earnings before taxes	**99,961,108**	54,422,550
Taxes		
Future income tax expense *(Note 11)*	**25,558,297**	5,290,432
Capital tax expense	**621,177**	553,119
	26,179,474	5,843,551
Net earnings for the year	**73,781,634**	48,578,999
Accumulated earnings, beginning of year	**100,253,217**	51,835,681
Retroactive application of change in accounting policy *(Note 5)*	**323,242**	161,779
Accumulated earnings, beginning of year, as restated	**100,576,459**	51,997,460
Accumulated earnings, end of year	**174,358,093**	100,576,459
Earnings per unit *(Note 6)*		
Basic	**1.61**	1.09
Diluted	**1.61**	1.09

See accompanying notes

Peyto Energy Trust

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31,

	2004	2003 (restated – Notes 2 & 5)
	$	$
Cash provided by (used in)		
Operating Activities		
Net earnings for the year	**73,781,634**	48,578,999
Items not requiring cash:		
Non-cash provision for bonuses	**15,944,936**	12,475,098
Future income tax expense	**25,558,297**	5,290,432
Depletion, depreciation and accretion	**40,879,937**	23,451,512
Change in non-cash working capital related to operating activities *(Note 13)*	**5,029,631**	6,402,059
	161,194,435	96,198,100
Financing Activities		
Issue of trust units, net of costs	**107,765,251**	39,002,261
Distribution payments	**(93,659,685)**	(40,855,610)
Increase in bank debt	**30,000,000**	70,000,000
Change in non-cash working capital related to financing activities *(Note 13)*	**(15,808,428)**	(2,203,827)
	28,297,138	65,942,824
Investing Activities		
Additions to property, plant and equipment	**(230,773,505)**	(139,423,682)
Change in non-cash working capital related to investing activities *(Note 13)*	**20,690,714**	(2,331,582)
	(210,082,791)	(141,755,264)
Net increase (decrease) in cash	**(20,591,218)**	20,385,660
Cash, beginning of year	**20,591,218**	205,558
Cash, end of year	**-**	20,591,218

See accompanying notes

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2004 and 2003

1. NATURE OF OPERATIONS

Peyto Energy Trust (the "Trust") is an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta. The Trust indirectly owns all of the securities of Peyto Exploration & Development Corp. ("Peyto") which entitles the Trust to receive all cash flow available for distribution from the business of Peyto after debt service payments, maintenance capital expenditures and other cash requirements. The unitholders of the Trust are entitled to receive cash distributions paid by the Trust and are entitled to one vote for each Trust unit held at unitholder meetings. The Trust units trade on the TSX under the symbol "PEY.UN". The Trust's principal business activity is the exploration for and development and production of petroleum and natural gas in western Canada.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. The financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the Trust's accounting policies summarized below.

These financial statements include the accounts of Peyto Energy Trust and its wholly owned subsidiaries, Peyto Exploration & Development Corp. and Peyto Operating Trust.

Joint operations

The Trust conducts a portion of its petroleum and natural gas exploration, development and production activities jointly with others and, accordingly, these consolidated financial statements reflect only the Trust's proportionate interest in such activities.

Property, plant and equipment

The Trust follows the full cost method of accounting for its petroleum and natural gas properties. All costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges related to exploration and development activities. All general and administrative costs are expensed as incurred.

The Trust evaluates its petroleum and natural gas assets to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves plus the lower of cost and market of unproved properties exceed the carrying value of the oil and gas assets. If the carrying value of the petroleum and natural gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves plus the lower of cost and market of unproved properties. The cash flows are estimated using the future product prices and costs and are discounted using a risk-free rate.

Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20% or more, in which case a gain or loss would be recorded.

All costs of acquisition, exploration and development of petroleum and natural gas reserves (net of salvage value) and estimated costs of future development of proved undeveloped reserves are depleted and depreciated using the unit of production method based on estimated gross proved reserves as determined by independent engineers. For purposes of the depletion and depreciation calculation, relative volumes of petroleum and natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Costs of unproved properties are initially excluded from petroleum and natural gas properties for the purpose of calculating depletion. When proved reserves are assigned to the property or it is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion. Depreciation of gas plants and related facilities is calculated on a straight-line basis over a 20-year term. Office furniture and equipment are depreciated over their estimated useful lives at declining balance rates between 20% and 30%.

Asset retirement obligation

Effective January 1, 2004 the Trust adopted the new accounting standard for asset retirement obligations. Under this new standard, the Trust records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings, and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability. The impact of the adoption of the new standard is described in Note 5.

Hedging

The Trust uses derivative financial instruments from time to time to hedge its exposure to commodity price fluctuations. The Trust does not enter into derivative financial instruments for trading or speculative purposes. The derivative financial instruments are initiated within the guidelines of the Trust's risk management policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Trust enters into hedges of its exposure to petroleum and natural gas commodity prices by entering into crude oil and natural gas swap contracts, options or collars, when it is deemed appropriate. These derivative contracts, accounted for as hedges, are not recognized on the balance sheet. Realized gains and losses on these contracts are recognized in petroleum and natural gas revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. Premiums paid or received are deferred and amortized to earnings over the term of the contract.

If hedge accounting were not followed, these derivative contracts would be treated as freestanding derivative financial instruments. Any resulting financial asset or liability would be recognized in the balance sheet and measured at fair value, with changes in fair value recognized currently in income.

Effective January 1, 2004, the Trust adopted the new accounting guideline for hedging relationships. The guideline describes the conditions necessary for a transaction to qualify for hedge accounting, the formal documentation required to enable the use of hedge accounting and the requirements to assess the effectiveness of hedging relationships. Also, early in 2004, an amended accounting abstract became effective which requires financial instruments that are not designated as hedges to be recorded at fair value on the balance sheet with changes in fair value recognized in earnings. The adoption of the guideline and amended abstract had no impact on the Trust's financial position as at January 1, 2004.

Revenue recognition

Petroleum and natural gas sales are recognized as revenue when title passes to purchasers, normally at pipeline delivery point for natural gas and at the wellhead for crude oil.

Measurement uncertainty

The amount recorded for depletion and depreciation of property, plant and equipment, the asset retirement obligation and the ceiling test calculation are based on estimates of gross proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be significant.

Future income taxes

The Trust follows the liability method of tax allocation. Under this method future income tax assets and liabilities are determined based on differences between financial reporting and income tax bases of assets and liabilities, and are measured using substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse.

3. PROPERTY, PLANT AND EQUIPMENT

	2004	2003 (restated – Note 5)
	$	$
Property, plant and equipment	**616,422,327**	384,788,369
Accumulated depletion and depreciation	**(85,180,541)**	(44,489,575)
	531,241,786	340,298,794

At December 31, 2004 costs of $28,663,020 (December 31, 2003 - $25,319,789) related to undeveloped land have been excluded from the depletion and depreciation calculation. Amounts related to 2003 have been restated for the adoption of new accounting standards for asset retirement obligations.

Adoption of the new guideline for petroleum and natural gas accounting using the full cost method, as outlined in Note 2, had no effect on the Trust's financial statements, based on the ceiling test prepared on the initial adoption on January 1, 2004 using the commodity price forecasts of the Trust's independent reserve evaluators. The Trust performed a ceiling test calculation at December 31, 2004 resulting in the undiscounted cash flows from proved reserves plus the lower of cost and market of unproved properties exceeding the carrying value of petroleum and natural gas assets. The impairment test was calculated at December 31, 2004 using the following independent engineering consultant's forecasted prices:

	2005	**2006**	**2007**	**2008**	**2009**	**Thereafter (2)**
Edmonton Ref Price ($CDN/bbl)(1)	50.22	47.76	44.69	41.62	39.16	+2%
AECO ($CDN/mmbtu)	6.78	6.52	6.26	6.00	5.73	+2%

(1) Future prices incorporated a $0.82 US/CDN exchange rate.
(2) Percentage change of 2.0% represents the change in future prices each year after 2009 to the end of the reserve life.

4. LONG-TERM DEBT

The Trust has a syndicated $300 million extendible revolving credit facility. The facility is made up of a $20 million working capital sub-tranche and a $280 million production line. The facilities are available on a revolving basis for a period of at least 364 days and upon the term out date may be extended for a further 364 day period at the request of the Trust, subject to approval by the lenders. In the event that the revolving period is not extended, the facility is available on a non-revolving basis for a one year term, at the end of which time the facility would be due and payable. Outstanding amounts on this facility bear interest at rates determined by the Trust's debt to cash flow ratio that range from prime to prime plus 0.75% for debt to cash flow ratios ranging from less than 1:1 to greater than 2.5:1. A General Security Agreement with a floating charge on land registered in Alberta is held as collateral by the bank. The average borrowing rate for 2004 was 3.7% (2003 – 4.7%).

5. ASSET RETIREMENT OBLIGATIONS

The new accounting policy, as outlined in Note 2, has been applied retroactively with restatement of prior periods. As a result of the retroactive application, the comparative statement of earnings for 2003 has been restated. The effect of the change on net earnings and earnings per trust unit for 2004 and 2003 was immaterial.

The following December 31, 2003 balances were restated as a result of the change:

	As previously Reported $	**Adjustment** $	**As Restated** $
Property, plant and equipment	338,413,384	1,885,410	340,298,794
Asset retirement obligations	888,407	1,391,004	2,279,411
Future income taxes	44,945,541	171,164	45,116,705
Accumulated earnings	100,253,217	323,242	100,576,459

The total future asset retirement obligations are estimated by management based on the Trust's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Trust has estimated the net present value of its total asset retirement obligations to be $3.3 million as at December 31, 2004 based on a total future liability of $14.3 million. These payments are expected to be made over the next 50 years. The Trust's credit adjusted risk free rate of 7% and an inflation rate of 2% were used to calculate the present value of the asset retirement obligations.

The following table reconciles the Trust's total asset retirement obligations:

	2004 **$**	2003 $
Carrying amount, beginning of year	2,279,411	861,390
Increase in liabilities during the period	860,453	1,312,561
Settlement of liabilities during the period	-	-
Accretion expense	188,970	105,460
Carrying amount, end of year	3,328,834	2,279,411

6. UNITHOLDERS' CAPITAL

Authorized: Unlimited number of voting trust units

Issued and Outstanding

Trust Units (no par value)	Number of Shares/Units	Amount $
Balance, December 31, 2002	43,418,188	19,230,677
Share issue costs, net of tax	-	(10,615)
Exercise of stock options	33,334	134,336
Shares converted to trust units	(43,451,522)	(19,354,398)
Trust units issued on conversion of shares	43,451,522	19,354,398
Trust units issued by private placement	1,943,600	29,873,132
Balance, December 31, 2003	45,395,122	49,227,530
Trust units issued by private placement	330,150	9,013,095
Trust units issued	2,000,000	85,300,000
Trust unit issue costs	-	(4,587,599)
Balance, December 31, 2004	47,725,272	138,953,026

Units to be Issued

On December 31, 2004 the Trust completed a private placement of 582,500 trust units to employees and consultants for net proceeds of $27,052,850. The trust units were issued on January 4, 2005. On December 31, 2003 the Trust completed a private placement of 330,150 trust units to employees and consultants for proceeds of $9,013,095. The trust units were issued on January 2, 2004.

Per Unit Amounts

Earnings per unit have been calculated based upon the weighted average number of units outstanding during the year of 45,855,517 (2003 – 44,430,031). There are no dilutive instruments outstanding.

7. ACCUMULATED CASH DISTRIBUTIONS

Peyto's strategy is to distribute approximately 50 percent of funds from operations to our unitholders on a monthly basis with the balance being withheld to fund capital expenditures. Management is prepared to adjust the payout levels to balance desired distributions with our requirement to maintain an appropriate capital structure. During the year, the Trust paid distributions to the unitholders in the aggregate amount of $93.7 million (2003 - $40.9 million) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit
January 2004	January 30, 2004	February 16, 2004	$0.15
February 2004	February 27, 2004	March 15, 2004	$0.15
March 2004	March 31, 2004	April 15, 2004	$0.15
April 2004	April 30, 2004	May 14, 2004	$0.17
May 2004	May 31, 2004	June 15, 2004	$0.17
June 2004	June 30, 2004	July 15, 2004	$0.17
July 2004	July 30, 2004	August 16, 2004	$0.17
August 2004	August 31, 2004	September 15, 2004	$0.17
September 2004	September 30, 2004	October 15, 2004	$0.17
October 2004	October 29, 2004	November 15, 2004	$0.19
November 2004	November 30, 2004	December 15, 2004	$0.19
December 2004	December 31, 2004	January 14, 2005	$0.19

8. OPERATING EXPENSES

The Trust's operating expenses include all costs with respect to day-to-day well and facility operations. Processing and gathering income related to joint venture and third party natural gas reduces operating expenses.

	2004	2003
	$	$
Field expenses	**12,187,102**	9,971,948
Processing and gathering income	**(4,976,947)**	(3,466,373)
Total operating costs	**7,210,155**	6,505,575

9. MARKET AND RESERVES BASED BONUSES

The Trust awards bonuses to employees and key consultants. The bonus structure is comprised of market and reserves based components.

Under the reserves based component, the bonus pool will be initially comprised of 3% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity and distributions, of proved producing reserves calculated using a constant price at December 31 of the current year and a discount rate of 8%.

($ million except unit values)	2003	2004	Change
Net present value of proved producing reserves @ 8% based on constant external engineer 2005 price forecast	880.0	1,138.0	258.0
Net debt before bonus	(162.5)	(197.1)	(34.6)
2004 distributions	(93.7)	-	93.7
Net value	623.8	940.9	317.1
Equity adjustment factor*			88%
Equity adjusted increase in value			277.8
2004 Reserves based bonus @ 3%			8.3

*Equity adjustment factor is calculated as the percent increase in value per unit divided by the total percent increase in value

Under the market based component, rights with a three year vesting period are allocated to employees and key consultants. The number of rights outstanding at any time is not to exceed 7% of the total number of trust units outstanding. At December 31 of each year, all vested rights are automatically cancelled and, if applicable, paid out in cash. The bonus is calculated as the number of vested rights multiplied by the total of the market appreciation (over the price at the date of grant) and associated distributions of a trust unit for that period. A tax factor of 1.333 is then applied to determine the amount of the bonus to be paid. The market based bonus for 2004 was based on 1.0 million vested rights at an average grant price of $16.81, average cumulative distributions of $2.73 and the five day weighted average closing price of $47.54 (2003 – 1.0 million rights, average grant price of $15.37, cumulative distributions of $0.90 per unit and five day weighted average closing price of $27.36).

The total amount expensed under these plans was as follows:

	2004 **$**	2003 $
Market based bonus	**44,607,873**	17,405,380
Reserves based bonus	**8,333,000**	-
Total	**52,940,873**	17,405,380

Compensation costs as at December 31, 2004 related to 1.6 million non-vested rights with an average grant price of $20.76 was $63.1 million of which a non-cash provision for future compensation expense of $12.5 million was recorded at December 31, 2003 and an additional $15.9 million was recorded in 2004.

10. PEYTO ENERGY TRUST REORGANIZATION

The following costs were incurred as part of the plan to reorganize Peyto into a trust which was effective July 1, 2003.

	$
Cash payout of stock options	**40,896,442**
Bonuses on cancellation of former Peyto stock option plan	**1,810,000**
Financial advisory, accounting and legal fees, and preparation and printing of the Information Circular	**1,500,000**
	44,206,442

11. FUTURE INCOME TAXES

	2004 **$**	**2003** (restated) $
Earnings before income taxes	**99,961,108**	54,422,550
Statutory income tax rate	**38.87%**	40.75%
Expected income taxes	**38,854,882**	22,177,189
Increase (decrease) in income taxes from:		
Non-deductible crown charges	**19,990,378**	17,665,105
Resource allowance	**(15,714,733)**	(12,886,311)
Corporate income tax rate change	**-**	(7,344,113)
Attributed Canadian Royalty Income (ACRI)	**2,205,065**	(1,813,847)
Trust distributions	**(20,917,147)**	(12,464,270)
Other	**1,139,852**	(43,321)
Future income tax expense	**25,558,297**	5,290,432

The net future income tax liability comprises:

	2004 **$**	**2003** (restated) **$**
Differences between tax base and reported amounts for depreciable assets	**81,931,159**	52,134,293
Accrued expenditures	**(10,052,825)**	(4,469,380)
ACRI carryforwards	**-**	(2,323,754)
Share and debt issue costs	**(50,890)**	(88,051)
Provision for asset retirement obligation	**(1,152,442)**	(136,403)
	70,675,002	45,116,705

At December 31, 2004 the Trust has tax pools of approximately $303.9 million (December 31,2003 - $189.0 million) available for deduction against future income.

12. FINANCIAL INSTRUMENTS

The Trust is a party to certain off balance sheet derivative financial instruments, including fixed price contracts. The Trust enters into these contracts with well established counterparties for the purpose of protecting a portion of its future earnings and cash flows from operations from the volatility of petroleum and natural gas prices. The Trust believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term and notional amount do not exceed the Trust's firm commitment or forecasted transaction and the underlying basis of the instrument correlates highly with the Trust's exposure. A summary of contracts outstanding in respect of the hedging activities at December 31, 2004 is as follows:

Crude Oil Period Hedged	**Type**	**Daily Volume**	**Price (CAD)**
January 1 to March 31, 2005	Fixed price	500 bbl	$50.85/bbl
January 1 to March 31, 2005	Fixed price	200 bbl	$50.65/bbl
January 1 to March 31, 2005	Fixed price	200 bbl	$53.25/bbl
January 1 to March 31, 2005	Fixed price	300 bbl	$57.50/bbl
April 1 to June 30, 2005	Fixed price	500 bbl	$48.85/bbl
April 1 to June 30, 2005	Fixed price	200 bbl	$49.25/bbl
April 1 to June 30, 2005	Fixed price	200 bbl	$51.85/bbl
April 1 to June 30, 2005	Fixed price	300 bbl	$57.35/bbl
July 1 to September 30, 2005	Fixed price	250 bbl	$54.08/bbl
July 1 to September 30, 2005	Fixed price	350 bbl	$56.08/bbl
July 1 to September 30, 2005	Fixed price	200 bbl	$59.02/bbl
October 1 to December 31, 2005	Fixed price	300 bbl	$54.35/bbl
October 1 to December 31, 2005	Fixed price	250 bbl	$57.52/bbl

Natural Gas Period Hedged	**Type**	**Daily Volume**	**Floor (CAD)**	**Ceiling (CAD)**
Nov. 1, 2004 to March 31, 2005	Costless collar	10,000 GJ	$5.50/GJ	$8.00/GJ
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$6.65/GJ	
Nov. 1, 2004 to March 31, 2005	Costless collar	10,000 GJ	$6.00/GJ	$7.65/GJ
Nov. 1, 2004 to March 31, 2005	Fixed price	10,000 GJ	$6.97/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$6.95/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.08/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.14/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.56/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.75/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.50/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.71/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.70/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.80/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.45/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.55/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.70/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.00/GJ	
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.27/GJ	

Based on dealer quotes, had these contracts been closed on December 31, 2004, the Trust would have realized a gain in the amount of $11.1 million.

Subsequent to December 31, 2004 the Trust entered into the following contracts:

Crude Oil Period Hedged	Type	Daily Volume	Price (CAD)
April 1 to June 30, 2005	Fixed price	200 bbl	$63.70/bbl
July 1 to September 30, 2005	Fixed price	200 bbl	$53.12/bbl
July 1 to September 30, 2005	Fixed price	100 bbl	$54.35/bbl
July 1 to September 30, 2005	Fixed price	200 bbl	$62.22/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$52.07/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$53.15/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$55.20/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$60.50/bbl
January 1 to March 31, 2006	Fixed price	300 bbl	$53.85/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$54.58/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$57.65/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$58.90/bbl

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.42/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.65/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.80/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.90/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.01/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.11/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.40/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.50/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.60/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.70/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.80/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.91/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.01/GJ

Credit Risk

A substantial portion of the Trust's accounts receivable is with petroleum and natural gas marketing entities. The Trust generally extends unsecured credit to these companies, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Trust's overall credit risk. Management believes the risk is mitigated by the size, reputation and diversified nature of the companies to which they extend credit. The Trust has not previously experienced any material credit losses on the collection of accounts receivable. Of the Trust's significant individual accounts receivable at December 31, 2004, approximately 50% was due from one company (December 31, 2003 – 75%).

The Trust may be exposed to certain losses in the event of non-performance by counter-parties to commodity price contracts. The Trust mitigates this risk by entering into transactions with counter-parties that have investment grade credit ratings.

Interest rate risk

The Trust is exposed to interest rate risk in relation to interest expense on its revolving demand facility. At December 31, 2004, the increase or decrease in earnings for each 1% change in interest rate paid on the outstanding revolving demand loan amounts to approximately $1.8 million per annum.

13. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital balances

	2004 **$**	**2003** **$**
Accounts receivable	**(17,881,727)**	(22,250,168)
Prepaid expenses and deposits	**(130,497)**	(4,237,728)
Due from private placement	**(18,066,972)**	(9,013,095)
Accounts payable and accrued liabilities	**43,326,215**	30,648,569
Capital taxes payable	**406,355**	(90,196)
Cash distributions payable	**2,258,543**	6,809,268
	9,911,917	1,866,650
Attributable to financing activities	**(15,808,428)**	(2,203,827)
Attributable to investing activities	**20,690,714**	(2,331,582)
Attributable to operating activities	**5,029,631**	6,402,059

	2004 **$**	**2003** **$**
Cash interest paid during the year	**6,904,809**	4,738,866
Cash taxes paid during the year	**214,822**	643,315

14. RELATED PARTY TRANSACTIONS

A director of the Trust is a partner of a law firm that was paid $430,705 for legal services for the year ended December 31, 2004 (December 31, 2003 - $866,379). The fees charged were based on standard rates and time spent on matters pertaining to the Trust and its subsidiaries.

15. COMMITMENTS

The Trust is committed to payments under operating leases for office space as follows:

	$
2005	417,790
2006	363,780
2007	363,780
	1,145,350

16. SUBSEQUENT EVENTS

On February 15, 2005, on private placement basis, 87,500 trust units were issued to employees and consultants at a price of $51.43 per trust unit for proceeds for $4.5 million.

Peyto Exploration & Development Corp. Information

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Vice-President, Exploration

Darren Gee
Vice President, Engineering

Scott Robinson
Vice President, Operations

Sandra Brick
Vice President, Finance

Stephen Chetner
Corporate Secretary

Directors

Ian Mottershead
Rick Braund
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Michael MacBean

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